

**COMMENTS OF CONSTELLATION ENERGY COMMODITIES GROUP, INC.
AND CONSTELLATION NEWENERGY, INC.
ON THE ILLINOIS POWER AGENCY’S DRAFT 2012 PROCUREMENT PLAN**

Now comes Constellation Energy Commodities Group, Inc. (“CCG”) and Constellation NewEnergy, Inc. (“CNE”) (collectively “Constellation”) and, pursuant to Section 16-111.5 of the Public Utilities Act (220 ILCS 5/16-111.5) (the “Act”), submits these comments to the Illinois Power Agency (“IPA”) draft procurement plan (“Draft Plan”) for the generation supply to eligible retail customers of Commonwealth Edison Company (“ComEd”) and Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Public Service Company d/b/a AmerenCIPS, and Illinois Power Company d/b/a AmerenIP (collectively, “Ameren”) for the period of June 2012 through May 2017.

I. Background

CCG is a power marketer authorized by the Federal Energy Regulatory Commission to sell energy and capacity and certain ancillary services at market-based rates. CCG focuses on serving the needs of distribution utilities, co-ops and municipalities that competitively source their load requirements. CCG also sells natural gas and other commodities at wholesale, both in the United States and abroad, and holds interests in exploration and production companies. CCG does not own any physical assets for the generation, transmission, or distribution of electric power and has no retail electric customers or service territories. However, CCG bids energy, capacity and ancillary services on behalf of generation-owning affiliates into the markets administrated by PJM Interconnection, L.L.C. and the Midwest Independent Transmission System Operator, Inc.

CCG has participated in the competitive procurement processes under which contracts for the electric power and energy needs of Ameren and ComEd have been awarded since the end of the transition period at the end of 2006. In the 2006 auction process, CCG was awarded certain tranches in the ComEd and Ameren auctions. Since 2008, CCG has been an active participant in all of the Commission and IPA proceedings and workshops related to the adoption and development of procurement plans for ComEd and Ameren. CCG has been a successful participant in many of these procurement events over the past few years.

CNE provides electricity and energy-related services to retail customers in Illinois as well as in 15 other states and the District of Columbia, and serves over 14,000 megawatts of load and over 10,000 customers. CNE holds a certificate as an alternative retail electric supplier (“ARES”) from the Commission to engage in the competitive sale of electric service to retail customers in Illinois. Since the introduction of customer choice in the Illinois electric industry in 1999, CNE has actively participated in the Illinois retail market. CNE has actively participated in nearly every regulatory proceeding before the Commission involving electric industry restructuring and has served as an advocate for fair and competitive open markets that are designed to provide customers with an array of competitive options. Additionally, CNE is one of the nation’s leading solar developers, designing, financing, and constructing solar projects that can help Illinois meet its renewable portfolio standard and solar carve-out. In addition, CNE is one of the more active ARES who are now providing service to thousands of Illinois homeowners and renters.

The most recent round of procurements in Illinois, which attracted a large number of qualified bidders and ultimately winning bidders, demonstrates the benefits of the competitive procurements when part of a well-run process. Based upon CCG's experiences in procurement events in Illinois and elsewhere, and CNE's experience serving industrial, commercial, and residential customers, Constellation has a number of recommendations to improve the IPA's draft procurement plan. Additionally, Constellation has unique expertise to assist the IPA in this first procurement in which IPA must purchase a minimum amount of solar power.

II. SUMMARY OF RECOMMENDATIONS

Based on its expertise over the years in other procurement events in Illinois and other jurisdictions, its experiences in Illinois as an ARES, and as a leading solar developer, Constellation proposes the following overarching recommendations for improvements to the draft procurement plan to be overseen by the IPA:

- Use Full Requirements Products To Minimize Customer Risks;
- Limit the Use of Long-Term Renewables;
- Exclude Clean Coal ;
- Balance the Procurement Across All Sizes of Solar Development;
- Establish a Procurement Schedule That Supports Retail Competition;
- Reduce Regulatory Uncertainty;
- Streamline the Application, Credit, and Contracting Processes;
- Streamline REC Procurement; and
- Provide Flexibility For Bidder Signatures.

A. Use Full Requirements Products To Minimize Customer Risks

In order to procure supply required to meet the needs of “eligible retail customers”, as defined within the Act, the Draft Plan should be modified to use full

requirements, load following (“full requirements”) products. The IPA is given discretion to procure products individually, or in combination.¹ The IPA should take into consideration the fact that customers bear greater risk with separate block products, because the shape and quantity of the load is not known, and should modify the Draft Plan accordingly by procuring full requirements contracts.

The benefits offered by a full requirements approach have never been greater than this upcoming procurement cycle due to the likelihood that the number of utilities’ bundled customers and underlying load will be reduced -- potentially dramatically -- during that time. The advent of purchase of receivables/utility consolidated billing, an increasing number of ARES indicating an interest in serving residential and small commercial customers, and the development of an ICC “Price to Compare” to research retail price offers, development of referral programs, and local communities moving forward with Municipal Aggregation plans, all support the proposition that “the policy supporting competitive electricity markets will continue and strengthen, and that a portion of the eligible retail consumers currently served through the IPA portfolio will migrate towards ARES options.”² As the IPA acknowledges, “recent developments indicate that significant reductions to the barriers to retail competition in residential markets are on the near-term horizon.”³ As a function of the unknown pace of migration of eligible customers to ARES, “[t]he portfolio is exposed to load uncertainty risk.”⁴

The Full Requirements Approach Best Fulfills the IPA’s Statutory Mandate

¹ 220 ILCS 5/16-111.5(b)(3)(iii).

² *Draft Plan*, p. 3.

³ *Id.* at 9.

⁴ *Id.* at 8.

A full requirements approach will best meet the requirements of Illinois law. It is important to keep in mind that “costs” to customers may include not only the prices paid by customers for IPA-procured supply, but the risks and lost opportunities they may face under a particular IPA plan. A full requirements approach will limit risks to customers by shifting them from the IPA, ComEd and Ameren to wholesale suppliers, while promoting opportunities for customers by providing well-defined, competitively-procured default service supply that provides appropriate benchmarks for comparisons to product offerings of retail electric suppliers (“RESs”).

As risks and costs to ComEd and Ameren appropriately are passed on to their customers, it follows that the full requirements approach limits the risk to utilities’ customers by shifting them largely to full requirements product suppliers. To explain, full requirements products provide consumers with insurance for the duration of the contract by shifting risk to wholesale suppliers. The situation faced in 2008 by Wellsboro Electric Company (“Wellsboro”) – a Pennsylvania utility procuring its default service requirements through a managed portfolio approach – provided documented evidence as to the benefits of shifting such risk; Wellsboro faced a market “surprise” and had to seek permission from the Pennsylvania Public Utility Commission on January 30, 2008, to recover in excess of \$2 million in additional congestion costs from its customers because of an unexpected congestion event.⁵ Wellsboro’s customers did not have the “insurance” provided by a full requirements supplier for such an event and, as a result, had to bear the

⁵ See *Joint Statement of Commissioner Kim Pizzingrilli and Vice Chairman James H. Cawley*, Commission Docket No. P-2008-202057 (issued Feb. 28, 2008) (“Wellsboro Feb. 2008 Decision”) at p.1.

burden themselves for the surprise rise in costs, as the Pennsylvania Public Utility Commission approved the pass through of such costs on February 28, 2008.⁶

An IPA plan relying on full requirements products provides a proper balance by obtaining the most competitive prices for consumers, while appropriately placing risks such as volume risk on wholesale suppliers. Support for this notion comes from an important study on Pennsylvania's energy future by Dr. Susan F. Tierney, a nationally recognized energy policy expert, former Assistant Secretary for Policy at the U.S. Department of Energy, and former Commissioner at the Massachusetts Department of Public Utilities.⁷ Dr. Tierney documents that, through competitive full requirements procurements, wholesale suppliers bring many benefits because of their abilities and skills.⁸

Bidders Possess Superior Expertise In Managing Portfolios

A diverse pool of wholesale full requirements product suppliers provide the most cost-effective method of management for eligible retail customers. Under full requirements product procurements, utilities provide to potential bidders prior to procurements, and to winning bidders on an ongoing basis afterwards, all of the load data for their individual customer classes. Wholesale suppliers are specialists in the area of portfolio management, and have greater resources, expertise and ability to appropriately utilize this data to manage portfolios of supply at the least possible cost, by allocating the costs for their operations over much larger load obligations throughout the country.

⁶ See Wellsboro Feb. 2008 Decision at p.1.

⁷ See *Pennsylvania's Electric Power Future: Trends and Guiding Principles*, Susan F. Tierney, Ph.D., Analysis Group (January 2008) ("2008 PA Market Study").

⁸ See 2008 PA Market Study at p.11 (stating that full requirements service "taps into the abilities and skills" of different wholesale market participants).

Moreover, such suppliers are able to draw from their substantial experience throughout PJM, MISO and in other jurisdictions to develop proprietary models of customer behavior and switching patterns, to refine these models, and to better analyze the local data provided by utilities. These wholesale suppliers pass on the efficiencies they achieve due to their sophisticated risk management skills and experience in the form of more competitive bids for full requirements products in competitive procurements. Wholesale suppliers have already invested in, and continue to make significant investment in acquiring, experts in each specific type of market which makes up full requirements supply.

At Constellation, for instance, hundreds of employees are involved in the process of providing full requirements service to utilities and customers around the country, serving tens of thousands of megawatts of various types of full requirements load from coast to coast. Constellation employs a team of seasoned portfolio managers for large regional portfolios that serve Constellation's customers' full requirements loads. Constellation must ensure that any transaction that goes into Constellation's entire portfolio of obligations is accounted for at the end of each day, and that requirements for the entire load are met continuously for every hour of every day of every week. A team of strategists continuously develops and improves computer models to keep track of all of the variable inputs that go into providing full requirements service; these strategists provide and analyze various scenarios that Constellation's portfolio managers may face. In addition, a fundamentals group constantly researches basic supply and demand in fuel and power markets in order to monitor macroeconomic trends that affect the costs of serving load. A 24-hour power trading desk trades power in the hour ahead, day ahead,

and week ahead markets each day of the week, in order to help manage Constellation's supply portfolio. Moreover, power managers and traders monitor and trade in not only the PJM and MISO markets, but also those in New York, New England and other markets throughout the U.S.; fuel managers do the same as fuel markets have direct effects on power markets. Similar resources focus on fuel oil, natural gas, coal, currency, emissions and renewable energy markets. Full-time meteorologists on Constellation's team continually monitor and predict the weather, so that Constellation's team can plan for weather effects on load requirements, and adjust supply accordingly. The task of meeting full requirements load supply additionally requires controllers, schedulers and dispatchers. Supporting all of these operations is a team of regulatory specialists and attorneys that monitor and participate in regulatory and legal activities which affect energy markets.

A wholesale supplier's greater expertise in these activities represents a valuable asset in evaluating and engaging in transactions for not only for complex hedges and other energy products, but for more common products in a portfolio such as block and spot market purchases. Increased levels of expertise and the ability to take on and manage a large portfolio's risks and responsibilities enable a wholesale supplier such as Constellation to provide significant competitive benefits over a smaller, less sophisticated market participant. Moreover, a wholesale supplier has the added expertise necessary to enter into more complex transactions which can provide additional appropriate management and hedging tools to further drive down costs.

Each of the tasks and positions described for Constellation's team plays an integral role in being able to drive down a wholesale supplier's costs of meeting load

requirements and provide the most reliable, up-to-the minute improvements and adjustments to a portfolio of resources, from which all of the supplier's customers will benefit. Without the benefits of accurate and around-the-clock weather monitoring and predicting, if an IPA plan estimates a need and purchases block products ahead of time to meet a utility's expected eligible retail customer load for the summer, one can, for instance, evaluate a situation where there happens to be an unusually hot week in the middle of July. The utility may face a situation where, because of the unusually hotter weather, homes and businesses are requiring *much* more electricity to run their air conditioners. If the IPA plan did not accurately predict how much load it would have in that week, because of that inability to accurately predict and react to the weather, the utilities may face a situation where they need to purchase in the spot market the additional supply that it requires at *high* electricity rates because, as demand for electricity increases around the region during a hot week, supply becomes constrained and prices for limited supply increase. The utility's consumers will bear the burden of the costs of this inability to accurately predict and plan for the weather in real-time.

Constellation and other wholesale suppliers continually monitor and predict the weather as part of their portfolio management function and are able to react in real-time and adjust supply accordingly and efficiently, with an incentive to keep costs low. The costs for all of the above types of expertise are mitigated significantly by utilizing a well-developed infrastructure and spreading the overhead for such activities across a supplier's entire portfolio of tens of thousands of megawatts of supply obligations across the country. Additionally, the costs for full requirements product suppliers to provide such service for a utility's eligible retail customers will be highly constrained by the very

competitive nature of this business, because wholesale suppliers throughout the market have operations similar in structure to those of Constellation, and will compete to serve a utility's eligible retail customers at the lowest cost. In addition, it is important to point out certain significant results from a recent analysis ("2010 Procurement Structure Analysis") conducted on behalf of Narragansett Electric Company d/b/a National Grid's ("National Grid"), and filed in the Rhode Island Public Utilities Commission's ("RIPUC") proceeding to consider National Grid's procurement structure for Standard Offer Service ("SOS"), Rhode Island's equivalent of utility supply service to eligible retail customers.⁹ The 2010 Procurement Structure Analysis provides an important and unique technical assessment based on advanced modeling, to compare and contrast "the relative costs and risks of different approaches to serve mass market customers, and how different approaches could impact customers' supply rates."¹⁰ While the Analysis suggests that a managed portfolio approach may, in fact, generally be cheaper than a full requirements structure, it is cheaper only by the narrowest of margins – *roughly only \$0.72/MWh*.¹¹ However, for this very limited benefit in cost due exclusively to the price for supply, consumers will be faced with *considerably more costs due to increased risks*.¹²

⁹ *Analysis of Standard Offer Service Approaches for Mass Market Customers*, RIPUC Docket No. 4041 (submitted Jan. 22, 2010) ("2010 Procurement Structure Analysis")

¹⁰ 2010 Procurement Structure Analysis at p.2.

¹¹ *See* 2010 Procurement Structure Analysis at p.12 and p.15 (explaining that the full requirements Structure results in an expected SOS rate of only \$0.72/MWh more than an alternative Managed Portfolio Approach).

¹² *See* 2010 Procurement Structure Analysis at p.20.

Any Incremental Premium Is Outweighed By Insulating Customers From Risk

It is true, however, that wholesale suppliers bidding on full requirements products may indeed place a certain value on the risk that they assume, for instance, for customer migration. The calculation for this monetization will depend on an individual wholesale supplier's perception of the level of such risk, its ability to manage the risk and its appetite for assuming the risk. By removing the potential for monetization and management of this risk by suppliers, a managed portfolio approach takes the actual risk and places it on consumers. In other words, it is a zero sum game. Customers bear each "cost," either in the price or in the form of an assumed risk. This type of shifting of risks directly to consumers fundamentally alters the nature of the product being provided.

Proponents of a managed portfolio approach often make claims that these monetizations and costs are exclusive to full requirements products. This claim, however, represents the false assumption that products such as block products in a managed portfolio approach will avoid (or else place on customers) most of the risks that are monetized in a full requirements product. In fact, block products include all of the same risks – and, in turn, monetization of risks – as full requirements products for items including, but not limited to, rising fuel costs, inflation, new energy taxes, market rule changes, market price changes prior to bid acceptance, and changes in credit standing. It follows that the only risk that may not be priced into the costs for block products is that of load variation, including variation due to customer migration. However, as explained above, if the fixed costs for the added benefits of full requirements products – *including* for load variation – are highly constrained through the competitive nature of full requirements product procurements, then it would be difficult to imagine that a managed

portfolio approach could result in more competitive prices than those achieved under the full requirements product procurements.

Detractors of full requirements structures also often suggest that a profit is added into a bid which is otherwise avoided when purchasing other products that may be procured under a managed portfolio approach. In reality, any product that is purchased in the wholesale markets – e.g., whether a full requirements product, a block product or a spot market purchase – will include in its price some level of profit that the supplier is willing and able to receive. Basic economic principles suggest that this is the case. When a seller sells a product – whether he is selling oranges, widgets or electricity – he seeks a return on his costs of producing the product. Basic economic principles also suggest that the price that a seller is “willing” to sell his product for will be constrained by the price he is “able” to sell his product for, so that in a competitive procurement, where only the lowest price from a pool of sellers is accepted, each seller will have an incentive to drive down the price at which he is “willing” to sell his product. This competitively constrained price for a full requirements product will include a seller’s perceived monetizations of risk as well as a profit on the overall full requirements product. Depending on a supplier’s perception of the level of risks, its ability to manage risks and its appetite for assuming risks, a supplier may have an ability to drive down further its underlying costs and overall prices. This especially is true for suppliers that are able to spread their costs across a large portfolio of supply obligations – if a supplier experiences lower revenue or a loss due to one of its obligations, for example, it is able to offset it against earnings across its entire portfolio of obligations. A utility relying on a managed portfolio approach has neither the competitive incentives to drive down its costs

for managing risks nor the ability to hedge its obligations and costs across a broad, multi-regional portfolio.

Finally, it is important to keep in mind that all of these allegations against full requirements products regarding relative costs appear not to be borne out when carefully analyzed – once again, the well-developed 2010 Procurement Structure Analysis suggests that the difference in consumers’ prices for accepting the costs of increased risks under a managed portfolio approach rather than placing such risks on suppliers through a full requirements structure is roughly *only* \$0.72/MWh.¹³

B. Limit the Use of Long-Term Renewables

The Draft Plan should not include the purchase of long-term renewable contracts. The Draft Plan does not contain sufficient justification for procuring long-term renewable contracts for a second year in a row – from a legal perspective, from a cost perspective, or from a policy perspective.

Long-term procurements are not required under the Act as part of the procurement. Rather, the only vehicle for entering into long-term contracts for renewable resources is through the Renewable Resources Budget (to which utilities and ARES both pay). Indeed, as the Draft Plan notes, the Act requires that a five-year time horizon be considered when formulating a Plan.¹⁴ To the extent that the Draft Plan seeks to procure products that fall outside of that window, the IPA does not possess such authority.

¹³ See 2010 Procurement Structure Analysis at p.12 and p.15 (explaining that the full requirements product structure results in an expected SOS rate of only \$0.72/MWh more than an alternative Managed Portfolio Approach).

¹⁴ *Draft Plan*, p. 5.

The Draft Plan fails to satisfy the requirement that it “ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability.” It contains no analysis or objective view of the market showing that these long-term contracts are in the best interests of consumers. For example, it contains no data or analysis of the long-term renewable contracts awarded under last year’s Plan, and their costs to consumers or other effects on the market.

The provisions of the Plan – particularly those done under the auspices of the Renewable Portfolio Standards (“RPS”) -- have a direct impact on competitive wholesale and retail markets and, ultimately, on consumers’ interests. While the electric utilities entering into long-term contracts have full cost pass-through protection, customers ultimately will pay. Additionally, given the fact that such procurements are based on a “forecast” where no competitive market actually exists. Moreover, they have little or nothing to do with promoting competition, given that the developers have no exposure to competitive market outcomes. As has been seen in the past, long term contracts prevent customers from realizing the benefits of the substantial price reductions that renewable technologies have seen.

Although ARES are not themselves parties to the long-term contracts, ARES are nevertheless directly affected by their use. The premiums for renewable energy implicit in the 20-year, long-term contracts will be included in the annual calculation of the RPS bill-impact cap. By definition, this also means that the premiums implicit in the 20-year, long-term contracts will also be included in the RES funded Alternative Compliance Payments (“ACP”) since the ACP rate is a direct derivation of the IPA’S RPS

procurement price. Since by law at least 50% of RES RPS compliance is via payment of ACPs, the premiums created by these contracts will potentially increase prices for all Illinois customers, not just eligible retail customers served by the IPA. 220 ILCS 5/16-115D(d).

The stated goals of minimizing customer bill impacts and providing a funding source for long-term renewable energy contract premiums via the IPA Renewable Energy Resources Fund is a preferable and statutorily correct approach to hedge any asserted impact of carbon controls on the state and to support the development of incremental renewable resources in the state. Further, since the payments that have been received and are anticipated can be reasonably projected, there is no reason that the IPA cannot utilize those funds in a procurement for long term renewable resources delivery and therefore capture any purported benefits of current federal renewable energy incentives and hedging of the impact of potential federal carbon controls.

Additionally, inclusion of long-term contracts needlessly complicates the IPA's procurement activities going forward. The IPA Renewable Energy Resources Fund procurement "shall not exceed the winning bid prices paid for like resources procured for electric utilities required to comply with 1-75 of this Act."¹⁵ This statutory provision is another reminder of the intent of the Illinois General Assembly as it relates to long-term contracting. There are greater complexities of using long-term contracts than shorter-term energy or energy plus renewable energy credits ("RECs"), when the true costs are not known and are subject to change over time. As the Draft Plan notes, "[m]eeting the RPS obligation is growing more complicated over time with volume requirements, budgets, and the costs of pre-existing contract obligations all operating in a variable

¹⁵ 20 ILCS 3855/1-75.

manner. Additionally, because the forward cost curve governing the applied costs for RECs delivered under the LTPPAs is confidential, a final RRB for each utility cannot be presented in this Draft Plan.”¹⁶ Such complexities will only increase this year and in future years. As acknowledged by the IPA, this hinders the ability of the IPA to actually **meet** the RPS standard. “The presence of the competing solar and wind carve-outs and their wide cost differences coupled with revenue variance increases the risk of the IPA portfolio not meeting its procurement goals in future years.”¹⁷ Anything that can be done to streamline the RPS process, to provide greater transparency, and to ensure that the RPS standard is able to be met, while not adversely affecting customers, should be given great weight; long-term contracts run counter to that fundamental premise.

C. Exclude Clean Coal

The Draft Plan calls for the solicitation of proposals from existing and planned “clean coal” facilities, setting forth generalized specifications.¹⁸ However, there is little justification for a “clean coal” component of this year’s Draft Plan, which constitutes a major change from prior Plans. Additionally, few details are provided for the planned solicitation itself, or what is to occur after the solicitation.

There is scant justification for inclusion of a clean coal solicitation as part of the Draft Plan. The Draft Plan indicates that “Section 75 of the Act includes a requirement that annual procurement plans include electricity generated by clean coal facilities.”¹⁹ However, a thorough reading of Section 1-75 of the IPA reveals no such requirement.

¹⁶ *Draft Plan* p. 49.

¹⁷ *Id.* at 49.

¹⁸ *Id.* at 54-55.

¹⁹ *Id.* at 54.

Rather, the Act's directive that the IPA encourage the development of coal resources is limited to the issuance of bonds financed by the Illinois Finance Authority, not with regard to procurement plans.²⁰

As further justification, the Draft Plan also notes that there are clean coal standards that go into effect in Illinois in 2025.²¹ The Draft Plan further notes that “federal incentives to support the repowering of an existing power plant in Illinois as a Clean Coal Generation facility are available”.²² It is unclear why it is necessary or prudent to seek solicitations for long-term contracts more than a decade earlier than any such requirement. Certainly, when federal funding is so readily available, whether or not long-term contracts such as contemplated under the Draft Plan exist is irrelevant to whether or not such facilities will ultimately be built. Indeed, the Draft Plan implicitly recognizes that long-term contracts under the Plan are not necessary for the development of “clean coal” facilities. This can be seen from the fact that the Draft Plan requires that, as a condition of eligibility, the project sponsors “[d]emonstrate a viable plan for securing all of the necessary capital required to support the development, engineering, construction and startup and commissioning of the clean coal facility.”²³ Moreover, the benefits and realities of “clean coal” have yet to be thoroughly explored. As has been seen in Illinois and reported in the press, estimates for these technologies have skyrocketed, even before construction.²⁴ Whether such facilities will even be built

²⁰ 20 ILCS 3855/1-75.

²¹ *Draft Plan* at 54.

²² *Id.* at 4.

²³ *Id.* at 55.

²⁴ “Soaring price of FutureGen clean-coal plant could singe Illinois Consumers”, *Crain's Chicago Business*, September 5, 2011 (noting estimated costs increased by more than a third since obtaining federal funding in 2010).

remains to be seen. It would therefore be prudent to hold off on any solicitation for the procurement period being contemplated under this Draft Plan.

As noted above, the Draft Plan lacks basic detail on the proposed coal solicitation. The Draft Plan, for example, indicates that it will seek proposals for both Utilities for up to 250 MW.²⁵ However, it is not clear how or why the IPA arrived at a desired amount of 250 MW. Nor is it clear whether the 250 MW is per utility or in the aggregate and, if the latter, what the allocation of the MWs procured would be between the utilities.

A key component of any element of the Draft Plan is that the resources be “cost-effective”,²⁶ which is particularly challenging in the context of the “clean coal” solicitation, for a number of reasons. First, it is not at all clear what the planned procurement period would be, though one may assume that the requirement for a commercial in-service date of December 31, 2017, contemplates a delivery period beginning in 2018, at the earliest. Second, as noted above, there are (and may likely be) few qualifying facilities. Of note, the Draft Plan does not provide any indication that they expect any (not to mention how many) qualifying bidders. It is generally recognized within the context of competitive procurements that a lack of winning bidders may render a procurement non-competitive. To the extent that the solicitation receives only a handful of responses, what are the criteria to assess whether or not the responses constitutes a competitive procurement? That issue is not addressed. Third, given the dearth of such facilities, not to mention the lack of any organized markets with meaningful long-range forecasts to support this portion of the Draft Plan, it may be impossible to determine what constitutes a cost-effective resource. Certainly, there is no

²⁵ *Draft Plan*, p. 54.

²⁶ 20 ILCS 3855/1-5(6); 220 ILCS 5/12-103 (a).

objective criteria identified in the Draft Plan, nor even a methodology and process by which any responses to the solicitation are to be weighed. There is simply not enough information included in the Draft Plan to be able to meaningfully consider such a product, even if the underlying assumptions of the Draft Plan were correct.

D. Balance the Procurement Across all Sizes of Solar Development.

Distributed generation (“DG”) sources, including solar, provide many benefits. These benefits include the reduced need for new transmission, reduced line losses as distributed energy is generated and consumed on-site, reduced distribution upgrades through the extension of useful lives of lines and transformers, reduced need to upgrade transformers to support load growth, and enhanced distribution system performance through electricity counter-flow and reduced low-end voltage sags. DG also helps protect appliances by providing improved power quality that defends against surges and sags. DG is less vulnerable to security threats and rolling blackouts, and it has a significantly lower environmental footprint than other forms of renewable generation that require additional land use. A competitive DG market in Illinois will spur significant competition, as the barriers to entry for developing small systems are far lower than for large scale generation. This competition will bring downward pressure to costs for the solar industry throughout Illinois, and benefit ratepayers accordingly.

To date, however, the IPA’s auctions have successfully driven investment only in utility-scale renewable energy generation. To promote a balanced market, Constellation suggests that the IPA hold separate procurements for solar renewable energy credits (SRECs) from distributed solar energy systems. While the precise size limitations of

such procurements should be open to stakeholder discussion, it is important to hold separate auctions for residential, commercial, and utility scale projects, as each of these categories builds at different price points due to increasing economies of scale.

Experience in other jurisdictions has also shown that it is necessary to discourage underbidding and place-holding from developers without the intent to actually bring projects to fruition. Too often, developers have deliberately under-bid into auctions, or held spaces in queues for the sole purpose of re-selling their place in line. This can be discouraged through instituting the following requirements as part of any procurement:

- (1) proof of site control in the form of a sale or lease agreement with appropriate contingencies for regulatory approvals,
- (2) developer experience requirements of at least five megawatts of solar previously developed,
- (3) facility diagram requirements,
- (4) refundable deposits of \$20 per kilowatt,
- (5) time limit of one year for providing proof of necessary permits, and
- (6) requirement that systems be operational within two years.

If utilized together, these requirements can go a long way to ensuring that the goals of the Plan are met. Without such requirements, some jurisdictions have seen a substantial majority of awarded projects never be built.

E. Establish a Procurement Schedule That Supports Retail Competition

Many of the 2011 procurements took place several weeks later than those same procurements had occurred in the past and were the latest in history since the creation of the IPA in 2007. That timing undoubtedly contributed to approved utility tariffs regarding new rates being made available by ComEd a mere one day before those rates went into effect. Upon completion of the procurements, utilities must run the numbers

through their respective rate translation mechanisms to arrive at a particular price per kWh for bundled service customers. Holding procurements so close in time to June 1st, necessarily backs up the timeline of when those new rates can effectively be published.

Delays in release of the tariffs and charges cause substantial confusion and competitive harm in the retail market. Last year was the first year in which there was meaningful opportunity for switching to retail electric suppliers in the residential market. There are currently thirteen (13) RESs licensed to serve residential customers in ComEd's service territory, and eight RESs licensed to serve residential customers in the Ameren Illinois service territory. (<http://www.pluginillinois.org/res.aspx>). RESs may have found it difficult to go to market with offers that were attractive to customers, given that changes to utility bundled rates were imminent, but without knowledge as to those revised rates and tariffs.

Although the Draft Plan calls for procurement events to be held earlier than occurred for the 2011 Plan, To the extent that procurements are to occur in the same year as the start of the new June-May cycle, as the Draft Plan currently contemplates, the procurement events should be held in late February or early March. Holding all procurement events during that time will have no material negative impact on the procurements themselves, and the timing will benefit suppliers and, ultimately, retail customers. The Commission Order ultimately approving the IPA plan should establish a schedule that permits calculation of new rates sufficiently in advance of their effective date, and require that utilities file and make available approved tariffs and charges not less than two weeks before new rates go into effect.

F. Reduce Regulatory Uncertainty

The time period between the submission of bids and the timing that potentially winning suppliers are notified should be shortened, to the greatest extent possible. Both the IPA and the Commission are to be commended for reducing the time period between submission of bids and contract execution. The most recent IPA Plan resulted in submission of potentially winning bids in a shorter time frame than the outside limits established under the law, and the Commission likewise expeditiously evaluated and approved the results of the procurement events during this most recent procurement cycle. However, further improvements can be made in shortening the time period for “informal” notification to potentially winning bidders.

The longer that bids must remain open, and be subject to the possibility that bids will be renegotiated or rejected during a review process that does not define the criteria for such renegotiation or rejection, the greater the likelihood that consumers will ultimately be economically harmed. While bids are held open during the review process, bidders retain the risk that market prices will change suddenly or unexpectedly. This risk is particularly important in procurement events involving Block Energy Products, given the volatility in today’s market. Potential suppliers have to incorporate such risks in their bids to account for this time lag. These risks will necessarily translate into bid prices.

Decreasing the length of time between submission of the bid and notification of likely bid award decreases the risk that suppliers bear, which would likely lead to lower overall bid prices. Such a result is consistent with the legislative mandate that:

The Commission shall approve the procurement plan if the Commission determines that it will ensure adequate, reliable, affordable, efficient, and

environmentally sustainable electric service **at the lowest total cost over time**, taking into account any benefits of price stability.²⁷

Given that the Block Energy Products are standard wholesale energy products, the review of these bids should be relatively straightforward, and should not require negotiation or additional review time. Constellation appreciates the efforts by the procurement administrators to convey their recommendations to the Commission expeditiously, and the Commission's prompt action in reviewing those recommendations. However, any time that can be shaved off of the current process is of benefit to suppliers, and therefore ultimately will inure to the benefit of ratepayers.

Ideally, bids would be submitted in the morning with results as to likely winning bidders provided that same day. The review of bids for standard Block Energy Products should be relatively straightforward, and should not require additional time. At most, next day notification of likely winning bidders should be provided. Scheduling procurements for earlier in the week (preferably Monday or Tuesday) will best ensure that bidders will not need to hold prices open unnecessarily over a weekend. This is of particular importance for the energy procurement, in which there is the greatest price volatility.

G. Streamline the Application, Credit and Contracting Processes

Constellation recognizes and appreciates the strides that have been made through previous procurement cycles for improvements in standardizing products and contracts, and recommends that the IPA and the Commission take this opportunity to make further refinements in this year's Draft Plan.

²⁷ 220 ILCS 5/16-111.5(d)(3) (emphasis added).

The process could benefit from streamlining and standardizing contracts. The three products are currently procured under three distinct contracts - one for energy, one for capacity, and a third for RECs. New “master agreements” are entered into each year for each product, with language in the agreements inserted to try to tie them together, both across products and across years. Entering into new contracts for each product each year is inefficient. The master agreement should be a true master agreement – there should only be one agreement, containing separate confirmations for each product. Each year, additional confirmations could be entered into pursuant to the existing master agreement. The master agreement could and should be used for procurements in multiple years, updating as necessary through the amendments during the annual process, rather than entering into new contracts with slightly different contract terms each year. Using a single master agreement to procure all products across multiple years would significantly reduce the administrative burden on bidders, the procurement administrator, the procurement monitor, and the Commission. Reducing the administrative burden on bidders could potentially lead to an increase in the number of bidders and a decrease in the cost of the products procured.

H. Streamline REC Procurement

Although the Commission has made improvements between and among the REC procurements over the years, it could benefit from further streamlining. Previous year’s REC procurements were held on different days, which was not optimal in that it resulted in different clearing prices for essentially the same product. However, bidders were able to submit bids in the second procurement with knowledge of what had cleared in the first procurement. Currently, REC bids are due on the same day and at the same time in two

separate procurements, both using different forms. Additionally, bidders must determine how much to bid into each separate procurement event, once again resulting in the exact same product clearing at different prices. Given the nature of the product, there should be a single procurement process for both utilities, with the procurements linked, essentially acting as a single procurement. Bidders would submit a single form and a single bid that would be applicable to both utilities. The volumes for the winning bids would be split between ComEd and Ameren proportionately, based on each utility's individual REC requirements procurements, thus resulting in procurements that would clear simultaneously and optimally.

I. Provide Flexibility For Bidder Signatures

Given the number of forms to be signed at different times throughout the procurement process, the bidding rules should allow for some flexibility. Currently, ComEd requires that the same officer of a bidder sign each of the following forms: Part 1 Form, Part 2 Form, Master Agreement, Confirmation, and Supplier Fee Binding Agreement. Strict adherence to such a policy fails to recognize the fact that the same person may not be physically in the office each day, due to business travel, personal vacation, or unforeseen events. Ameren's rules take these exigencies into account, permitting a secondary signatory if the original signatory is unavailable for whatever reason; ComEd should be required to do the same.

III. Conclusion

As outlined above, reliance upon full requirements products achieves several benefits. The IPA can best access competitive wholesale markets by procuring full

requirements products, rather than by trying to purchase individual components of service (i.e., energy, capacity, RECs, etc.) on its own. Constellation therefore recommends that the IPA Draft Plan be modified as described herein.

Respectfully Submitted,

CONSTELLATION ENERGY COMMODITIES GROUP, INC.

A handwritten signature in black ink that reads "Cynthia Fonner Brady". The signature is written in a cursive, flowing style.

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Dated: September 14, 2011